

SCE's Comments to Question #4 Raised in the Counting Workshop, April 6-7, 2004**"When is a year in advance for purposes of assessing resource adequacy?"**

The Resource Adequacy Workshops on Counting Issues held on April 6-7, 2004, identified five issues that were not fully discussed during these workshops due to time constraints. These issues were placed on the agenda for the added workshop scheduled on April 26, 2004. SCE was assigned one of these issues as stated above.

Decision D.04-01-050 "...establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance..."¹ The issue is whether a "year in advance" is defined as: (1) twelve months in advance, (2) by the end of the previous calendar year, or (3) some other definition.

In SCE's Opening Comments on Resource Adequacy, dated March 4, 2004, SCE addressed the issue as follows²:

SCE defines "a year in advance" to be a calendar year prior to the summer month in question. For example, to meet the resource requirement of May 2008, the LSE will forward contract 90% of its peak demand plus reserve margin prior to the end of 2007. Therefore, the appropriate coverage of the peak demand that LSEs must demonstrate for May 2008 will be $(.90 * 1.15 * \text{peak demand})$ or 103.5% of the May 2008 peak demand, and the LSE will forward contract this capacity prior to December 31, 2007.

Other parties, including the working group dealing with the load forecast issues, have suggested setting the "year in advance" definition to mean that the required resources need to be confirmed by April (or earlier) in the year prior to the summer in question. For example, under one proposal, 90% of the May – September 2008 resource adequacy requirement would be forward contracted by April 30, 2007.

SCE makes its recommendation for many reasons, but the primary reason being that Conclusion of Law #7 in D.04-01-050 states that "The utilities shall meet this 15-17% requirement by no later than January 1, 2008." Since this 15-17% requirement is designed to be the target reserve level in the summer of 2008 it appears that this language allows the utilities until December 31, 2007 to meet this requirement. This language seems to impute that by meeting this reserve margin target by the last day of the preceding year that this will meet the "year in advance" requirement.

SCE also has two other considerations in mind: (1) minimizing the costs to ratepayers of meeting these resource adequacy requirements, and (2) having sufficient information available which will allow informed and logical procurement decisions for the following summer.

¹ D.04-01-050, page 11

² Footnote 6

SCE's recommendation would benefit ratepayers by providing LSEs greater flexibility to determine the optimum timing of their procurement activities in order to reflect more recent market conditions, economic conditions, regulatory changes, etc.

With a December 31 forward contracting deadline for the following summer's resource adequacy requirement, parties will have significantly more information with which to make procurement decisions. The following information will be more accurate in December prior to the summer in question (as opposed to April, 12 months prior to the summer) and will lead to improved estimates of resource adequacy requirements and supply availability:

1. Load forecasts can be finalized with a higher degree of certainty especially for smaller LSE's. The following information will be available to LSEs in December as opposed to April for the following year's summer peak:
 - Effectiveness of demand side and energy efficiency programs in reducing load during the peak hours.
 - More accurate forecasts of the following summer's peak
 - ESPs will have better knowledge of contracts that will expire or renew for the next year.
2. Better data regarding the online status of new generation projects.
3. Procuring by the end of Dec gives two benefits: 1) the primary one being more flexibility, and 2) the secondary one being more liquidity.
4. Determination of the Reliability Must Run (RMR) requirements. RMR studies by the ISO are completed by September of each year for the following year.
5. A better determination of the hydro availability for the next summer season. (October 1 is the start of the hydroelectric water year. At that time, the starting level of reservoirs for the hydro year is known, and projected hydro availability to meet the following summer's peak load can also be more accurately forecasted. Similarly, potential imports from hydroelectric resources in the Pacific Northwest can be better identified.)
6. The ISO's deliverability analysis integrating RMR, FTR, and other transmission planning studies should be completed.

For those who claim that the end of a prior calendar year is not a "year in advance," SCE responds that an April commitment date is no more in accordance with the Commission's decision. An April compliance date for the following year's resource adequacy requirement would effectively result in 17 months in advance requirement for September, 16 months advance for August, and so on. The "year in advance" would be exceeded in all months except May. SCE's proposal makes the most sense, will ensure better planning, and will likely be more cost-effective for ratepayers.

LOAD FORECASTING STRAWPERSON¹

Submitted 4/09/2004

Resource Adequacy Requirements Workshops in R.01-10-024

PREFACE

This report addresses several issues related to developing the load forecasts which D.04-01-050 requires LSEs to use in conjunction with a planning reserve margin to make forward commitments to resources. D.04-01-050 covers all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs.

This report has been prepared by a self-selected team of interested parties following the March 16, 2004 “kickoff” workshop in the resource adequacy workshops called by an ALJ Ruling dated February 13, 2004. This is final “strawperson” report, and the component sections have been discussed in two multi-party conference calls.

Pursuant to the direction of ALJ Cooke, this “strawperson” report has been scheduled to be discussed in an open public workshop on April 14, 2004.

I. WHO PREPARES LOAD FORECASTS FOR WHAT CUSTOMER BASE?

D.04-01-050 creates resource adequacy requirements for all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs. It is unclear who is to prepare load forecasts and what loads are to be included in these load forecasts.

The remainder of Section I discusses two options for preparation of load forecasts:

a. IOU for Its Current Customers and Expected Load Growth, and ESP for the Load of Its Current Customers and Their Expected Load Growth

The over-arching concern is that the load of EVERY customer is the responsibility of some load serving entity. One way to insure coverage is to agree on a methodology whereby the ESPs forecast of load during the forecast horizon is based on load projections of the current roster of ESP customers, including the growth in load of these customers as permitted by existing contracts as well as any reduction in load due to energy efficiency. The IOUs forecast, in contrast, will assume that all existing IOU bundled customers will remain on IOU bundled service and that all new customers will also take IOU bundled service. This methodology will insure that all customer loads, both existing and new customers, will be explicitly covered by an LSE.

Pros	Cons
The plus side of this methodology is that all customer loads, both existing and new customers are covered by an LSE forecast	This methodology will tend to overstate/understate the true load responsibility of ESP's /IOU's to the extent that customers change service providers during the forecast period.
This method does not require extensive “reconciliation” or “iteration” between the IOU forecast and the various ESP forecasts or among the ESP forecasts.	
This method allows for fairly straight-forward verification of IOU and ESP load forecasts as the recent historic loads of the current roster of each IOU's and each ESP's customer base is known.	

¹ As a collaborative effort to identify issues, this document does not have the endorsement of any party.

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b. All LSEs Prepare “Best Estimate” Load Forecasts

In this option both IOUs and ESPs (and eventually CCAs) prepare load forecasts that are their best estimate of what loads will be in the months of May-September one year ahead. For the IOU, presumably this takes into account normal load growth expected through new customer movement into the service territory, but other factors could be attributed to expected load growth. For example, the load forecast of the utility will have to account for variables such as a significant number of customer turn-offs, a city in the service territory who opts for Community Choice Aggregation or if a core/non-core market is established. For ESPs, this option proposes that ESPs provide load forecasts for their best estimate of the aggregate load they intend to be serving for each of the summer months at the point the filing is submitted. Even though direct access is suspended, load growth can occur by load switching from one ESP to another, and by increases in loads for individual customers under contract.

Pros	Cons
Most accurate reflection of loads LSEs actually intend to procure resources for	Does not permit accounting for all customer IDs
Some parties interpret this to be consistent with D.04-01-050, while others disagree.	Creates additional uncertainty associated with DA/CCA customer loads switching back to IOUs or from one ESP to another. In practice, would not necessarily support explicit accounting for all DA customers.
	Could be open to considerable “gaming” resulting in a number of customers who’s loads “fall through the cracks”.

II. WHAT IS THE NATURE OF THE LOAD FORECAST?

There are several non-controversial elements of the load forecasts that each LSE is to prepare. These are:

- The basic unit of measurement that LSE’s will be forecasting is hourly load in MWh. This means that variations in instantaneous load over an hour are ignored.²
- Each LSE is to prepare a load forecasts for each IOU service area in which it has customer loads. This means that an ESP serving customers across all three IOU service areas would prepare separate load forecasts for the grouping of its customers located in each IOU service area.

a. The Time Horizon of the Load Forecast

Each LSE should provide a forecast of its hourly loads for each of the five summer months early each year (somewhere between January and April) for the period May-September of the next year (e.g submission in 2005 for loads during May-September 2006). If there were to be review and/or reconciliation adjustments of a draft load forecast before it was finalized (see Section V.a) the draft would come early in each calendar year, and adjustments would take place through the end of March with a goal of load forecasts finalized by April (e.g by April 2005 for the projected loads May-September 2006).³

b. Inclusion of Losses in Load Forecasts

² There may be some discussion that peak demand should be expressed in MW rather than MWh. Historically, resource planning has centered on annual peak MW. In SCE’s experience, for recent recorded data, the annual peak MW and peak MWH are so close as to be interchangeable, and resource adequacy planning can be done on the basis of the forecast highest annual or monthly MWh observation.

³ See Section V.c for another option, which some parties prefer, but which other parties view as outside the scope of D.04-01-050.

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There are two options which define alternative extents to which losses are included within the load forecasts submitted by each LSE. These are:

(1) End-use metered usage plus losses up to the ISO-interface

This would be the definition of load that LSEs send to the ISO for settlement purposes. It is hourly load at the customer meter (either from hourly meters, or load profiled) plus distribution losses. Distribution loss factors by voltage level are published by the IOU's for all ESP's within their service area to use for ISO settlement purposes, so under the current process we are all using distribution losses calculated in a compatible manner. This definition does not adjust LSE load for transmission losses, UFE or any other adjustments.

Pros	Cons
Uses CPUC-approved method for adjusting for distribution system losses	Excludes a portion of losses traditionally included in "peak" measurements
Consistent with current ISO settlement processes.	Reduces "peak" loads which LSEs would have to satisfy leaving these the responsibility of the system operator
Does not require development and approval of a new method for computing additional losses beyond the CAISO-interface	
Consistent with current contractual structure whereby energy is purchased at the ISO interface.	Does not include either transmission losses or UFE which would be required in order for forecasting volumes to be converted to a "generation" concept. UFE and transmission losses could sum to as much as 5% at time of peak.

(2) End-use metered usage plus losses to the generation busbar

This is Option 1 above plus transmission losses, UFE and other adjustments reflected in the differences between SCADA real-time metered loads and end-use customer loads. To implement this option requires that these "transmission" losses be added to the losses included in Option 1. The real-time loads monitored by the ISO and the IOUs on their EMS (energy management systems) for their respective control areas are measured at "generation". This load is defined as the sum of all generation within the control area (net of self generation serving customer load on the customer side of the meter) plus the net of imports minus exports to the control area. It is a "top down" measure of load, as compared to the "bottom up" definition of customer load as reported by LSEs to the ISO for settlement, and it is real time.

Conceptually, this load at generation is greater than the load as measured at the ISO interface by the amount of physical transmission losses between the generators and the ISO interface, which is commonly referred to as a "transmission loss factor". Edison has found that, in practice, this "transmission loss factor" has to account for more than just the physical losses. It also has to account for UFE and probably accounts for metering discrepancies between the real-time EMS systems and the billing meters (and distribution loss factors) used for settlement. IOUs or the CAISO should provide to the CEC the forecast transmission loss factor for their area, and the CEC should apply it equally to all LSE load to convert them from "at the ISO interface" to "at Generation".

Pros	Cons
Consistent with traditional definition of system peak measurements	The above approach does not use a GMM/TMM approach. There may be an entity who could identify its specific transmission path and transmission loss factor (which might be lower than what the IOU says is the system average transmission loss factor).

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This method includes UFE and any other sources of losses, such as metering discrepancy.	Like the current CAISO settlement computations, makes all LSEs responsible for measurement errors that may be caused by a few entities
Creates an "all in" requirements forecast as it includes use, plus distribution losses, plus transmission losses, plus UFE.	Not consistent with current contracting practices in the industry where delivery is taken at the ISO interface, not at the generation busbar.
	Would require additional effort by IOUs and CAISO to identify "transmission" losses which should not be charged to CPUC-jurisdictional LSEs
	Because of the requirement for interval metering for DA customers >50 kW, ESPs generally have more accurate measurement of aggregate ESP hourly loads than do IOUs, thus non-IOU LSEs should be over-allocated UFE

c. Shape Information Characterizing the Load Forecast

This section discusses three alternatives and makes a recommendation. A recommendation is made because this topic is such a central issue for the entire resource adequacy forward commitment obligation.

(1) 720/744 hourly loads for each of the five summer months

This option would require each LSE to submit in chronological sequence the hourly loads for the five summer months of May through September. Each month would have either 720 or 744 hourly values.

Pros	Cons
Consistent with D.04-01-050 and may facilitate counting options other than peak hour.	Does not contain as much information as Option 2 (the 8760 version), thus inhibiting use of the compliance filings for other evaluation purposes.

(2) 8760 hourly loads from which five monthly peak shapes can be extracted

This option would require each LSE to provide the full annual hourly load forecast in chronological sequence. From these data, the hourly loads for the summer months could be extracted.

Pros	Cons
Contains the most complete information about LSE loads across the entire year, thus facilitating other analyses	Only the months May-Sept are really going to be used per D.04-01-050
	By requiring 8760 hourly loads, this method goes beyond the analyses of peak loads for the five summer months included in D.04-01-050 ⁴

(3) Five monthly peak shapes

⁴ The CEC participants suggested the CEC may end up requiring 8760 hourly loads to be filed by LSEs as part of the inputs which the industry will provide to the CEC's 2005 IEPR proceeding.

In this option, each LSE would report hourly loads for the highest 5, 10, or 20 hours in each of the five summer months. Using the load duration curve (LDC) as an analogy, the LSE would report the “top” of the LDC.

Pros	Cons
consistent with D.04-01-050 and ALJ Ruling dated 2/13/2004	Contains much less information than either option 1 or 2
minimum amount of work involved	Limits options with respect to counting of resources.
	Inconsistent with Section IV.a of this report, since it would be impossible to determine true coincident loads for the CAISO control area if LSEs only submit a limited number of their own “high load” hours without time stamping

(4) Recommendation

The load forecasting team recommends that option (1) be implemented. Option (3) is not workable, because chronological hourly loads are essential to understanding coincidence of individual LSE loads to form the CAISO control area peak. The method of coincidence adjustment proposed in Section IV.a could not be implemented without hourly loads. Option (2) may be outside of the scope of the monthly analyses required by D.04-01-050.

d. Quantification of Energy Efficiency and Customer-Side of the Meter Distributed Generation Impacts

It is understood that LSEs account for “price induced” load responses as part of their base load forecasts. This section addresses the impacts from program impacts that are not motivated by prices. Expected “real” energy efficiency program impacts and the amount of distributed generation on the customer side of the meter are separately subtracted from the LSE’s “base” load forecast (e.g. the net forecast is lower with these effects included than the gross forecast without them).

(1) Energy Efficiency (EE) Program Impacts

Energy efficiency load reductions for the forecast period should be deducted from the base load forecast, irrespective of how these programs are funded or who is the program delivery agent. For these purposes, “committed” energy efficiency (EE) refers to CPUC approved PGC- and procurement-funded programs.

Energy efficiency load reductions for forecasts are conceptually developed in two stages. For some forecasting methodologies, these two stages can be subsumed into a single process. The first stage is to determine the historical impact of energy efficiency programs. This can be done directly, by using the Commission adopted measurement protocols and procedures to determine program or measure-level savings. It can also be done indirectly, as through a forecasting model which captures the impact of historical load reductions. (This is the approach PG&E uses for PGC-funded EE.)

The next conceptual step is to extrapolate those load reductions into the future (in this case, for the next summer.) In the case of an explicit forecast, the measured program or measure-level impacts are extrapolated using CPUC approved budgets (“committed EE”) or budgets not yet approved by the CPUC (“uncommitted EE”). For year ahead forecasts, uncommitted EE will typically occur at the end of a funding cycle. For example, current EE budgets are approved through 2005, so forecasts for that year will be committed EE. When the forecast is not explicit, for example embedded in a forecasting approach, the forecasts made with the model will implicitly include historical levels of EE. A final step in most case is to provide the forecast in hourly detail. This generally utilizes historical load shape data at an appropriate level of desegregation.

As long as the steps of this process continue to be done under CPUC oversight, as for example, using the Commission’ adopted measurement studies or protocols, the resulting forecasts should be included without alteration in resource adequacy computations.

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As long as *all* LSEs do not administer their own energy efficiency funds/programs the coordination of IOU energy efficiency program impact assessments will be necessary for ESPs and, in the future, CCA's to include the appropriate amounts of energy efficiency savings in their load forecasts. Periodic re-evaluation of energy efficiency savings by all LSEs will be necessary to ensure proper quantification and application of this resource to load forecasts over time.

At this time, some EE may be applicable to ESP customers as well as IOU customers. In the future, the same may hold true for CCA customers. Since all LSEs are responsible for load forecasting and their own resource adequacy it is imperative that the real resource value of energy efficiency programs targeting their load be known. This may require unspecified information sharing in the future, perhaps using the CEC as an intermediary in their role of reconciling different LSE forecasts, and prorating EE impacts.

(2) Distributed/Self-Generation Resources

Incremental distributed/self generation (SG), which will serve customer load and will be located on the customer side of the meter, should also be deducted from the base load forecast.

As with committed EE, the IOU may be aware of SG installations that are fostered by IOU administered programs, which the ESP or the future CCA is not aware of. An IOU may have a forecast of the total amount of incremental SG but not know specifically whether units will be applied to bundled customers or DA customers. As with committed EE, the IOU could provide the CEC an annual allocation of incremental SG to DA customers based solely on the ratio of DA sales to total sales.

e. Treatment of Demand Response

The discussion of the treatment of demand response is separated into discussion of price responsive demand tariffs and programs versus treatment of interruptible / emergency load curtailment programs. Each of these two categories has two options.

(1) Price Responsive Demand Tariffs and Programs

There are two options for the treatment of price responsive demand tariffs and programs, which are intended to be implemented by the IOU when they are the "least cost" resource to be operated:

a) Distinguish Treatment on Dispatchability Characteristics

The impacts of PRD tariffs and programs which are not dispatchable by the LSE are subtracted from "base" load forecast. Dispatchable tariff and program impacts are carried as a supply resource.

In this option, price sensitive demand reduction are subtracted from the "base" load forecast only if the DR program is not dispatchable by the LSE. Under Alternative 1, demand reduction from dispatchable DR programs would be treated as a supply resource because this type of DR has the feel of a resource (ie., the demand reduction is dispatched like a resource), even though its effect is different than that of a supply in that it reduces demand rather than increases supply.

Arguments in favor of Alternative 1 (against Alternative 2):

Dispatchable DR is treated as a supply resource because it operates as a supply-side option. Since the "strike price" and dispatch terms are known in advance, the LSE can integrate these resources within its supply portfolio (including market transactions) to implement a "least cost dispatch". Based on past experience, the LSE can estimate what if any of the non-dispatchable DR will be available coincident with the LSE's peak demand requirements.

b) All PRD tariff and program impacts are subtracted from "base" load forecasts.

In this option, all price sensitive demand reduction is subtracted from the “base” load forecast regardless of whether a program is dispatchable by the LSE or not. For dispatchable DR programs, the LSE has the right to trigger a demand reduction at a pre-set strike price. For a non-dispatchable DR, the customer chooses when and at what price to reduce demand, and the LSE estimates the demand reduction associated with different price levels when preparing its load forecast.

Arguments in favor of Alternative 2 (against Alternative 1)

Price sensitive DR programs are treated consistently. That is, both dispatchable and non-dispatchable DR are treated as demand reduction because both result in a demand reduction regardless of whether the LSE has dispatch rights. When the LSE exercises its dispatch rights, it will reduce its demand and the reserves associated with that load reduction. In both cases, the LSE would not carry reserves for load that is not projected to materialize at a given price.

(2) Interruptible/Curtailment Programs for Reliability

There are two options for the treatment of interruptible or emergency programs, which are intended only to be operated when the reliability of the system is threatened:

a) Treat Impacts as a Supply Option

In this option, the impacts of interruptible tariffs and programs are not to be subtracted from “base” load forecasts, but rather carried as resources.

Arguments in favor of Alternative 1 (against Alternative 2):

Dispatchable DR is treated as a supply resource because the demand reduction associated with these programs is already part of the LSE’s reserves.

b) Treat Impacts as a Load Reduction

In this option, the impacts of interruptible tariffs and programs are subtracted from “base” load forecasts to the limit of each program.

Arguments in favor of Alternative 2 (against Alternative 1)

When the ISO calls for a Stage 2 curtailment, the LSE experiences a reduction in demand and associated reserves. The LSEs does not need to carry reserves on interruptible load since this is by definition non-firm load and the customer has been already been paid to curtail under prescribed rules. If treated as a “supply-side option”, in order to achieve the same effect, the expected demand reduction would need to be grossed by the required reserves in order to capture the no-reserve need for interruptible load.

f. Weather and other Short-Term Variations

Values for weather variables and other factors inducing short term variation in loads should be chosen to represent expected (50:50) loads for each of the five summer months.

III. REPORTING AND COMPLIANCE

This section of the report addresses a number of topics which are essential to be resolved for reporting and compliance purposes. Understanding these reporting and compliance purposes helps to define the nature of the load forecasts.

a. Timing of Annual Compliance Submittals

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There are two options which define when load forecasts are submitted as part of the annual process to determine compliance with resource adequacy requirements:

(1) Load forecasts are submitted as part of the IOU's current short term filing each spring

In 2002 and 2003 each IOU was required to submit short term procurement plans in the spring of the year and the CPUC issued a decision by the end of the year establishing procurement ground rules for the subsequent calendar year. This option presumes that this process is adapted to also address the resource adequacy commitment requirements as part of an annual short term filing. Thus, no later than April of each year all LSEs would file appropriate documentation to demonstrate that they had satisfied the year ahead commitment obligations for the months of May-September of the subsequent calendar year. A key portion of this documentation is their load forecast for at least these five summer months.

Pros	Cons
A single short term and compliance filing, which makes review of IOU filings more efficient	Non-IOU LSEs will be submitting compliance filings and no corresponding "going-forward" procurement filings are required for ESPs or CCAs
	Intermingling short term filings aimed at clarifying procurement rules for short term purchases with a compliance filing may be inappropriate

(2) A two-stage process of developing load forecasts

This option is designed to accommodate the coincidence evaluation/adjustment discussed in Section V.a of this report. Draft load forecasts would be submitted in January to the CEC, which processes them to adjust for coincidence and perhaps other factors beyond the knowledge of each LSE. These adjustments would be reported back to each LSE within a month. In stage two, final load forecasts are submitted as part of the compliance filing in April of each year (essentially the same as option (1) described above).

Pros	Cons
A specialized process for load forecast adjustments preceding actual compliance filings to demonstrate forward commitment obligations have been satisfied	Requires preparation of load forecasts without final versions of full calendar year data
The additional work of a two-stage process can result in reduced forward commitment obligations, thus saving money or identification of "cushion" represented by obligations based upon non-coincident peaks	Considerable additional analytic work
Factoring in "diversity" will lessen the tendency toward over-procurement of resources that will occur if diversity is ignored.	May result in additional proceedings regarding methodology of calculation and application of diversity factors.

b. Documentation of Load Forecast Reported by Each LSE

Load forecasts should be submitted with in-depth documentation sufficient to permit review of results and basic approach, including such items as:

- a) Historic hourly load for the previous year as used in CAISO settlement processes, adjusted for weather using an agreed-upon adjustment methodology
- b) Hourly values of the Load Forecast

- c) Basic documentation of customer counts⁵, methodology, program impacts included (EE, DG, PRD, etc.)
- d) Narrative explanation of any significant factors

These elements of documentation are necessary for any of the analyses discussed in Section V.c. A documentation submission requirement would be new to non-IOU LSE that they are not used to satisfying. At least for utilities, no greater effort is implied by the proposed documentation than would be required by CEC's biennial planning requirements. Both ESPs and IOUs suggest that such filings could create confidentiality concerns that would have to be resolved.

c. Confidentiality of Load Forecast Submittals⁶

The following are aspects of the confidentiality issue yet to be fully discussed or resolved, but that both IOUs and ESPs have raised:

- (1) All LSE-specific hourly load forecasts are confidential and will not be submitted to any reviewing entity except with that understanding. Access to such data will be limited and follow the usual non-disclosure agreement practices.
- (2) At some level of aggregation, loads are no longer confidential and such "higher level" results can be prepared and released by the reviewing entity(s). No discussion of at what level of load aggregation shifts from confidential to public has yet taken place.

It is likely that these confidentiality concerns exist for other categories of data which are part of these resource adequacy compliance filings, and therefore the confidentiality issue should be resolved in a comprehensive manner.

IV. USE OF LOAD FORECAST AS A BASIS FOR FORWARD COMMITMENT OBLIGATIONS

The ALJ Ruling dated February 13, 2004 raised the issue of confidence adjustments among LSE forecasts. This section of the report addresses how coincidence would be assessed from among filings submitted by LSEs, and then discusses options for making use of the diversity information gained from such an analysis.

a. Coincidence Analysis

The CEC proposes two possible methods for adjusting for the coincident control area peak load on the basis of the hourly load forecasts of each LSE, and then using this information to identify the each LSE's load at the coincident peak.⁷

(1) Computing Coincidence Directly from LSE Submitted Forecasts

This method assumes all LSEs within the CAISO control area provide hourly forecasted load for the summer months.⁸ The designated load for the forward obligation is based on each LSE's share of total load during the CAISO's coincident peak hours, rather than LSE loads on their individual peak days, using the following steps:

⁵ ESPs do not believe that individual customer by customer information should be provided. Aggregate counts of customers should be sufficient.

⁶ This section was inserted after the 3/26/2004 conference call at the suggestion of Art Canning. No one has yet volunteered to write this section up.

⁷ Note that these proposals require selection of either Option (1) or (2) in Section II.b for all LSEs.

⁸ Since there are numerous publicly-owned utilities within the CAISO control area, this method requires that either the CEC or the CAISO require a comparable hourly load forecast from entities outside the CPUC's jurisdiction. The CEC has the legal authority to require such load forecasts for all "utilities" in California, and the CEC is currently evaluating whether it will resume such a requirement.

- a) Calculate the times and amounts of CAISO forecasted peak hours by summing across all submitted LSE forecasts on an hour by hour basis, and finding the maximum five hours for the CAISO in each calendar month.
- b) Extract LSE loads at the time of each of the monthly CAISO peak hours, and calculate each LSE's share of the CAISO peak for each hour. Take the average of the shares.
- c) The individual LSE designated load is calculated as the product of the average share from (b) and either the CAISO monthly peak derived from either the aggregated forecasts, or the CAISO peak adjusted for transmission losses or other unaccounted for energy as described in Section II.b.
- d) Compare the shares from (b) to shares calculated the same way from the most recent year's actual weather-adjusted hourly loads. If the shares calculated from the forecast differ significantly from these historic data, then further review and possible adjustment may be appropriate.

Pros	Cons
Can be derived directly from forecast.	Requires forecasts from all LSEs in CAISO. Could use CEC forecasts for non-CPUC jurisdictional LSEs.
Coincidence adjustments based on the same days of the year are likely to produce less error due to weather adjustments that vary across LSEs.	The aggregation of hourly forecasts produced by different entities and forecast techniques may not produce a valid CAISO forecast. Analysis and calibration of the aggregate forecast should be done before adjustment for coincidence.

(2) Computing Coincidence Directly from Historic Adjusted Loads

In this approach a coincidence adjustment is derived from the LSE's load at the time of the monthly CAISO peak, relative to the LSE's own monthly peak. (The "share of the peak day" approach in the first alternative could also be used with historic data, but it would require an additional step to adjust the peak day shares for differential growth across LSEs).

- a) Calculate CAISO five monthly peak hours as in (1), using one year (or possibly more) of historic weather normalized hourly summer loads, to be provided by each LSE.
- b) Extract LSE loads at the time of each of the five CAISO peak hours of the month, and the LSE's own monthly peak hours. Calculate a coincidence factor as the average of LSE's load at the CAISO peak hours, divided by the average of the LSE's five peak hours.
- c) This coincidence factor is applied to the LSE's monthly peak forecast, adjusted for losses or other factors as needed.

Pros	Cons
Requires only historic adjusted hourly loads from non-CPUC jurisdictional LSEs. CEC could weather-adjust recorded data if needed.	Coincidence adjustment based on different days of the year may be more likely to produce erroneous measures of diversity due to differences in weather adjustment methods. (NYISO experience)
Coincidence analysis can be begun before forecasts are filed.	Averaging the coincidence factor over multiple years would be more reliable, but this may not be viable for ESPs with limited or highly variable history.

(3) IOU Service Area Coincidence with ISO System Load Based on Analysis of Temperature Data

As an aid to understanding of load diversity, a supplemental analysis in parallel to either of the above two options could be undertaken using temperature data for the three IOU service areas, which is available for 30 or 40 historical years. The CEC could take a weighted average temperature by service area and compare those service area temperatures to the weighted average for the ISO control area for the 40 historical years, and calculate a diversity of temperatures relative to the day of the ISO area hottest temperature. The CEC may have factors such as MW per degree Fahrenheit for each area, or could request and coordinate such analysis with the IOUs such that the temperature diversity could be converted to a peak hour MWh diversity. This would give a long term view of diversity and give insight as to frequency and probability of coincident high temperatures, but only looking at IOU total loads versus the ISO total load. This method gives no insight to diversity between bundled and DA load within an IOU service area. However, it does answer part of the diversity question with an analysis of long-term data, which is not available directly from LSE load data.

b. Use of Coincidence Results

To the extent that diversity among LSE hourly loads is found, what should be done with this information? The following are options:

(1) Adjust for Coincidence

In this option, each LSE's forward obligations would be explicitly reduced by adjusting the original LSE load forecast for a monthly coincidence factor so that the "final" LSE load forecast used for compliance determination is lower than the original, non-coincident one.

Pros	Cons
Forward obligations for a specific based upon that LSE's actual contribution to system peak	Implementation may require "finetuning" of language in D.04-01-050
If diversity is not taken into account then LSE's will be systematically over-procuring resources in "aggregate".	May result in additional proceedings regarding methodology of calculation and application of diversity factors.

(2) Ignore Coincidence

In this option the coincidence analysis described in Section V.a would not be used to adjust each LSE's load forecast or their forward commitment obligations relative to these load forecasts. Instead, the coincidence analyses would provide an understanding of the "cushion" provided by non-coincidence of individual LSE load forecasts and the benefits this has to further assure reliable system operation.

Pros	Cons
The diversity among individual LSE loads would create an additional "cushion" so that effective planning reserves were greater than the 15-17% of system peak adopted in D.04-01-050	LSE's obligated to acquire higher level of resources, perhaps 1-5% of there own peak loads, thus costing more money than if diversity were accounted for
Explicit coincidence analysis reveals the actual size of this "cushion"	Theoretically more correct to account for diversity directly than to use indirect means of "adjustment".
Avoid delays in approving compliance filings based on debates regarding calculation and application of diversity factors	

c. Analyses that could be Conducted for Each LSE's Submittal

The following are different analyses that could be conducted on each LSE's load forecast submittal once it has been filed. One or more of these analyses could be conducted, so there are elements of an evaluation process, not options. One or more different entities might be involved in such analyses.

- (1) Summation of each LSE's load forecast and comparison to CEC's IEPR results at the IOU service area and/or the IOU's own IOU service area load forecast as a gross check on plausibility of LSE load forecasts
- (2) Comparison of each LSE's load forecast to its previous resource adequacy compliance filings
- (3) Feedback to be provided by CPUC, CEC, and CAISO to an LSE about possible errors within the load forecast submittal.

The CEC believes that a rationale for conducting some degree of evaluation can be made as follows:

- (1) To evaluate the consistency and reasonableness of the aggregated load forecasts, each LSE provides the following:
 - a) An 8760 1-2 load forecast (year ahead)
 - b) Hourly loads for the previous year (or multiple years), adjusted for weather and other accounting protocols as needed.
 - c) Basic documentation
- (2) Evaluate whether historic LSE loads sum to historic CAISO and utility totals. The purpose of this step is to verify that all existing loads and losses are accounted for, and that accounting protocols for program effects, etc, appear to be followed.
- (3) Compare aggregated forecasts to UDC/IEPR/CAISO forecasts.
- (4) Evaluate whether individual LSE growth rates within plausible bounds. Are they consistent with historic trends, forecasted economic conditions, and/or explained by expected customer actions?
- (5) Attempt to resolve discrepancies with LSEs.
- (6) Report on remaining discrepancies and make recommendations.

V. OTHER ISSUES

The discussions among the load forecasting team have raised a number of additional issues that appear to be important to record, even though they are outside of the scope of the load forecasting "strawperson" and are perhaps incompatible with the language of D.04-01-050. Nonetheless, implementation of an effective body of resource adequacy requirements may mean that these topics must be ultimately addressed.

a. Necessity of Acquiring Hourly Load Forecasts for Non-Jurisdictional Entities

Section IV.a proposes a method whereby the CEC obtains individual hourly load forecasts from each LSE and uses these, plus additional data, to determine the CAISO control area peak in each month. Hourly loads from the non-jurisdictional entities, including municipal utilities and other entities outside of the jurisdiction of the CPUC, are necessary to implement this proposed method. There are several sources of such information, but at least one of them must be implemented in order to develop an accurate forecast of each LSE's load at the time of the CAISO's monthly peak.

b. Some Loads Are Highly Variable, Which May Need to Be Explicitly Addressed in Load Forecasting Protocols

Load forecasting for entities that do not serve a traditional customer base (non-traditional LSEs) requires different approaches for determination of their planning reserve requirements. Their loads must be forecast with tools that account for the underlying source of the demand.

The water pumping loads of the State Water Project and its water contractors are a good example. SWP loads are based upon the amount of water moved through the SWP's system of pumps, which amount varies significantly from year to year. Since future SWP loads are subject to fluctuating hydrology conditions, they may not be closely aligned with recent load history. There are corresponding impacts on the state water contractors at the point of local water deliveries as these agencies use more or less ground water pumping depending upon availability of surface water deliveries.

Load forecasts for non-traditional LSEs such as the SWP should reflect, where appropriate, acceptable levels of service risks and flexible delivery times. Establishing a reserve requirement using forecasted loads for May through September a year in advance may not make sense for a non-traditional LSE such as the SWP whose water delivery requirements are not known until the end of the precipitation season, which is typically the end of April in a current year. A load forecast a year in advance could vary over the full range of historic hydrology. Since non-traditional LSEs such as SWP have direct control over the timing of their loads with flexibility during a month, and most of its load is served during the off-peak periods when resource adequacy for a control area is generally not a concern, they should enjoy greater flexibility in load forecasting and establishing reserve requirements.

Pros	Cons
More accurate load forecasts	Requires greater documentation to explain how fluctuations were built into the load forecast
	Greater complexity in reviewing LSE submittals

c. Load Forecasts Covering the Period One and More Years Ahead

As described in Section II.a of this report, each LSE will provide a forecast in the spring of the year for each of the five summer months of the following year. Most LSEs will prepare forecasts with longer time horizons in order to appropriately consider a portfolio of resources to cover expected loads. In order to facilitate planning, these forecasts could be provided for a five-year forecast horizon. Thus, in April of each year forecasts would be provided for the period May-September of the next five years, e.g. submissions made in April 2005 for

May – September 2006

May – September 2007

May – September 2008

May – September 2009

May – September 2010

Pros	Cons
Lead time to build resources takes more than a one-year time frame.	One year ahead is the maximum commitment under the current rules, so no additional information needed for a compliance filing
A five-year ahead forecast would provide much better information for planning purposes.	ESP commercial contracts generally are not long-term in nature and, therefore, the ESP's ability to make long-term forecasts/commitments may be impacted.
A five-year ahead forecast would draw attention to the policy concern between directed planning and commercial feasibility.	

d. Rolling Twelve Month-Ahead Load Forecasts

Neither of the options described in Section I of this report provides a good method to address the expected load for ESPs. The first would require an estimate of the load under contract as of the point the forward planning process required a submittal, as though these were actually the expected load. As ESP's relationship with a customer is contractual, with a specified term, requiring an ESP to forecast load based on current customers may overstate ESP load and thereby require ESPs to secure, on a forward contract basis, reserves in excess of its requirements. Since

an ESP does not have a base of customers from which to spread costs, but instead incurs costs commensurate with customer commitments, such a strategy could have a deleterious affect on ESPs and the service they can provide their customers. The second method is better, since it allows the ESP to make an accurate forecast, but by requiring one perhaps 13 months ahead (April 2005 to May 2006) and one 17 months ahead (April 2005 to September 2006), it cannot adjust for changes in ESPs loads as time passes and more information becomes available.

ESPs recommend that the ESPs forecast load based on contracts that will be in effect during the one-year forward peak summer period. The load projections can then be refreshed on a rolling one-year forward basis during the summer, to update the information to reflect new contracts or contract renewals. For example, in May 2004, ESPs would refresh their May 2005 forecast, in June 2004, ESPs would refresh their June 2005 forecast, etc. Additionally, as load is contracted for within the one-year forward window, ESPs can forward contract for the summer period to the forecast to reflect the load under contract. This allows the ESP to fulfill the intent of the order, which is to forward contract for reserves to meet summer peak requirements. We believe the order allows for, does not prevent, an interpretation that the load forecast for the summer period can be updated monthly on a one-year forward basis.

e. Updating Load Forecasts and Obligations After Initial Filings

Once an LSE has submitted its annual load forecast and accounting to demonstrate compliance for forward commitment obligations, how are subsequent updates of LSE internal load forecasts (different ideas about growth or unexpected terminations of contracts with end-users, etc.) tracked and forward commitment obligations revised for the period shorter than one year ahead?

The following are options:

(1) Not tracked

Once the "final" either year ahead or update compliance report is completed, load transfers are not tracked and any reconciliation is left to LSE's (such reconciliation would be outside of the scope of compliance reporting)

(2) For compliance reporting, a category of load shifts is established and reported

Categories of LSE deficiencies and LSE overages due to load shifts reported, perhaps on a monthly basis.

(3) Establish a daily capacity trading market (PJM), adjusting for LSE load shifts

The concept is that LSEs must have a mechanism to true up the respective forecasts in order for it to match the actual load. One way to do this is through a secondary capacity market/auction (daily or monthly). Under this mechanism, a LSE could off load excess capacity or fulfill the additional capacity needs given changes in load. This capacity market would simply be a "reconciliation" market for "true-ups" and not a means by which LSEs would acquire all of their capacity needs. Another mechanism would be some sort of administrative reconciliation methodology that would capture load forecast differentials and somehow allocate penalties or overpayments appropriately amongst LSEs.

(4) Establish a monthly true-up capacity trading market (NYISO) adjusting for LSE load shifts

f. IOU Cooperation and Support to all Non-IOU LSEs (e.g., CCAs and ESPs)

If Non-IOU LSEs are required to meet the same resource adequacy and load forecasting requirements that IOUs are expected to meet, they will need a certain degree of cooperation and support from IOUs to be successful. R.03-10-003 is the forum in which most information exchange issues between future CCAs and IOUs are under discussions. Non load forecasting issues such as costs of information transfer between IOU's and CCA's should remain within R.03-10-003. However, specific information support issues to comply with resource adequacy requirements, such as those described below, should be addressed within this proceeding.

For new LSEs that do not have extensive historical load data on hand to calculate year- or more-ahead forecasts IOUs will need to be willing and able to provide sufficient historical load information to facilitate the best-informed LSE load forecasts. This may mean that for certain LSEs, CCAs for example, IOUs may need to provide up to 10 years of historical load data for a given city, county, or group of cities and counties (i.e., Joint Powers Authority). It will be imperative that this cooperation and coordination take place to ensure that accurate load forecasting occurs and resource adequacy requirements are met. Cooperation between IOUs and CCAs will also be required regarding economic forecasts that underpin load forecasts. Cooperation will also be required between IOU's and CCA's regarding load profiling data e.g. some CCA's may need to site more load profile meters to establish a statistically valid load profile sample for forecasting and other purposes.

APPENDIX C: NERC GADS Definitions

Appendix C

NERC GADS Definitions

Operation and Outage States

Actual Unit Starts

Number of times the unit was actually synchronized

Attempted Unit Starts

Number of attempts to synchronize the unit after being shutdown. Repeated failures to start for the same cause, without attempting corrective action, are considered a single attempt.

Available

State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Forced Derating (D1, D2, D3)

An unplanned component failure (immediate, delayed, postponed) or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage (U1, U2, U3, SF)

An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Maintenance Derating (D4)

The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage (MO)

The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a MO may occur anytime during the year, have flexible start dates, and may or may not have a predetermined duration.

Planned Derating (PD)

The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage (PO)

The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

Reserve Shutdown (RS)

A state in which a unit is available but not in service for economic reasons.

APPENDIX C: NERC GADS Definitions

Scheduled Deratings (D4, PD)

Scheduled deratings are a combination of maintenance and planned deratings.

Scheduled Derating Extension (DE)

The extension of a maintenance or planned derating.

Scheduled Outages (MO, PO)

Scheduled outages are a combination of maintenance and planned outages.

Scheduled Outage Extension (SE)

The extension of a maintenance or planned outage.

Unavailable

State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.

Time

Available Hours (AH)

- a. Sum of all Service Hours (SH); Reserve Shutdown Hours (RSH), Pumping Hours, and Synchronous Condensing Hours, or;
- b. Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).

Equivalent Forced Derated Hours (EFDH)*

The product of the Forced Derated Hours (FDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Forced Derated Hours During Reserve Shutdowns (EFDHRS)*

The product of the Forced Derated Hours (FDH) (during Reserve Shutdowns (RS) only) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Planned Derated Hours (EPDH)*

The product of the Planned Derated Hours (PDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Scheduled Derated Hours (ESDH)*

The product of the Scheduled Derated Hours (SDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Equivalent Seasonal Derated Hours (ESEDH)*

Net Maximum Capacity (NMC) less the Net Dependable Capacity (NDC), multiplied by the Available Hours (AH) and divided by the Net Maximum Capacity (NMC).

APPENDIX C: NERC GADS Definitions

Equivalent Unplanned Derated Hours (EUDH)*

The product of the Unplanned Derated Hours (UDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Forced Derated Hours (FDH)

Sum of all hours experienced during Forced Deratings (D1, D2, D3).

Forced Outage Hours (FOH)

Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

Maintenance Derated Hours (MDH)

Sum of all hours experienced during Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Maintenance Outage Hours (MOH)

Sum of all hours experienced during Maintenance Outages (MO) and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Period Hours (PH)

Number of hours a unit was in the active state.

Planned Derated Hours (PDH)

Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

Planned Outage Hours (POH)

Sum of all hours experienced during Planned Outages (PO) and Scheduled Outage Extensions (SE) of any Planned Outages (PO).

Pumping Hours

The total number of hours a turbine/generator unit was operated as a pump/motor set (for hydro and pumped storage units only).

Reserve Shutdown Hours (RSH)

Sum of all hours experienced during Reserve Shutdowns (RS). Some classes of units, such as gas turbines and jet engines, are not required to report Reserve Shutdown (RS) events. Reserve Shutdown Hours (RSH) for these units may be computed by subtracting the reported Service Hours (SH), Pumping Hours, Synchronous Condensing Hours, and all the outage hours from the Period Hours (PH).

Scheduled Derated Hours (SDH)

Sum of all hours experienced during Planned Deratings (PD), Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4) and Planned Deratings (PD).

APPENDIX C: NERC GADS Definitions

Scheduled Outage Extension Hours (SOEH)

Sum of all hours experienced during Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Scheduled Outage Hours (SOH)

Sum of all hours experienced during Planned Outages (PO), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).

Service Hours (SH)

Total number of hours a unit was electrically connected to the system.

Synchronous Condensing Hours

Total number of hours a unit was operated in the synchronous condensing mode.

Unavailable Hours (UH)

Sum of all Forced Outage Hours (FOH), Maintenance Outage Hours (MOH), and Planned Outage Hours (POH).

Unplanned Derated Hours (UDH)

Sum of all hours experienced during Forced Deratings (D1, D2, D3), Maintenance Deratings (D4), and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Unplanned Outage Hours (UOH)

Sum of all hours experienced during Forced Outages (U1, U2, U3, SF), Maintenance Outages (MO), and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Capacity and Energy

Gross Maximum Capacity (GMC)

Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal, or other deratings.

Gross Dependable Capacity (GDC)

GMC modified for seasonal limitations over a specified period of time. The GDC and MDC (Maximum Dependable Capacity) used in previous GADS reports are the same in intent and purpose.

Gross Available Capacity (GAC)

Greatest capacity at which a unit can operate with a reduction imposed by a derating.

Gross Actual Generation (MWh) (GAG)

Actual number of electrical megawatthours generated by the unit during the period being considered.

APPENDIX C: NERC GADS Definitions

Net Maximum Capacity (NMC)

GMC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Dependable Capacity (NDC)

GDC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Availability Capacity (NAC)

GAC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Actual Generation (MWh) (NAG)

Actual number of electrical megawatthours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

***Notes:**

- Equivalent hours are computed for each derating and then summed.
- Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

Equations

Availability Factor (AF)

$[\text{AH/PH}] \times 100 (\%)$

Equivalent Availability Factor (EAF)

$[(\text{AH} - (\text{EUDH} + \text{EPDH} + \text{ESEDH}))/\text{PH}] \times 100 (\%)$

Equivalent Forced Outage Rate (EFOR)

$[(\text{FOH} + \text{EFDH})/(\text{FOH} + \text{SH} + \text{EFDHRS})] \times 100 (\%)$

Forced Outage Factor (FOF)

$[\text{FOH/PH}] \times 100 (\%)$

Forced Outage Rate (FOR)

$[\text{FOH}/(\text{FOH} + \text{SH})] \times 100 (\%)$

Gross Capacity Factor (GCF)

$[\text{Gross Actual Generation}/(\text{PH} \times \text{GMC})] \times 100 (\%)$

Gross Output Factor (GOF)

$[\text{Gross Actual Generation}/(\text{SH} \times \text{GMC})] \times 100 (\%)$

Net Capacity Factor (NCF)

$[\text{Net Actual Generation}/(\text{PH} \times \text{NMC})] \times 100 (\%)$

APPENDIX C: NERC GADS Definitions

Net Output Factor (NOF)

$$[\text{Net Actual Generation}/(\text{SH} \times \text{NMC})] \times 100 (\%)$$

Scheduled Outage Factor (SOF)

$$[\text{SOH}/\text{PH}] \times 100 (\%)$$

Service Factor (SF)

$$[\text{SH}/\text{PH}] \times 100 (\%)$$

Computation Method Discussion

Each of the statistics presented is computed from summaries of the basic data entries required in each equation. The basic data entries are totaled and then divided by the number of unit-years in that data sample. This unit-year averaged basic data entry is then used in computing the statistics shown. Two examples of these computations are shown below:

Example 1:

$$\text{FOF} = [\text{FOH}/\text{PH}] \times 100 (\%)$$

$$\text{Where: FOH} = \frac{\sum_{i=1}^N \text{FOH}_i}{N}$$

$$\text{PH} = \frac{\sum_{i=1}^N \text{PH}_i}{N}$$

i = individual unit in any individual year

j = individual derating occurrence

N = number of unit-years considered

Example 2:

$$\text{EFOR} = \frac{\text{FOH} + \text{EFDH}}{\text{FOH} + \text{SH} + \text{EFDHRS}} \times 100$$

$$\text{Where: FOH} = \frac{\sum_{i=1}^N \text{FOH}_i}{N}$$

$$\text{SH} = \frac{\sum_{i=1}^N \text{SH}_i}{N}$$

APPENDIX C: NERC GADS Definitions

$$EFDH = \frac{\sum_{i=1}^N EFDH_i}{N}$$

$$EFDHRS = \frac{\sum_{i=1}^N EFDHRS_i}{N}$$

Note: All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

Average Number of Occurrences Per Unit-Year

$$= \frac{\text{Number of Outage and/or Derating Occurrences}}{\text{Number of Unit-Years}}$$

Average MWh Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Derating Type} \times \text{NMC (MW)}}{\text{Number of Unit-Years}}$$

Average Hours Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Derating Type}}{\text{Number of Unit-Years}}$$

Average Equivalent MWh Per Unit-Year

Computed as shown in the equation for **Average MWh Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average MWh Per Unit-Year** equation. Each equivalent hour is computed as follows:

$$\text{EQUIVALENT OUTAGE HOURS} = \sum \frac{\text{Derating Hours} \times \text{Size of Reduction}}{\text{NMC (MW)}}$$

Average Equivalent Hours Per Unit-Year

Computed as shown in the equation for **Average Hours Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average Hours Per Unit-Year** equation.

Notes:

--All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

APPENDIX C: NERC GADS Definitions

--Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

APPENDIX D

Draft #2

“STRAW-PERSON” DELIVERABILITY PROPOSAL

Deliverability is an essential element of any resource adequacy requirement. Specifically, Load Serving Entities (LSEs) must be able to show that the supplies they intend to procure to meet their load requirements can be delivered to load when needed. Otherwise, such resources are of little, if any, value for the purposes of resource adequacy.

The California Public Utilities Commission (CPUC) is considering how to require the LSEs to demonstrate the deliverability of the resources they procure in both their annual resource plans and their long-term resource plans. This is essential so that the LSEs will be able to “count” their resources to determine whether they satisfy the planning reserve margin, and to ensure sufficient coordination between resource planning and transmission planning.

This paper and three attachments offer a “Straw-Person” proposal for deliverability with technical details on this proposed methodology. Draft 1 of this paper was the focus of a six-hour meeting and a two-hour conference call involving approximately 30 participants, as well as written comments from eight participants as of April 5th. **Additional written comments on this Draft 2 are encouraged as a way to facilitate the on-going debate at the April 12-13 workshops.**

The stakeholder discussions and written comments raised a number of general policy issues that go beyond the scope of this paper. A number of these issues were listed in a March 26, 2004 memo from the ISO’s Phil Pettingill (on behalf of the Deliverability workgroup) to the entire Resource Adequacy service list. This paper carves out several other policy issues that could be separated from this proposed methodology and technical explanation for determining deliverability.

This proposed straw-person deliverability proposal consists of three assessments: Deliverability of Generation to the Aggregate of Load, Deliverability of Imports, and Deliverability to Load Within Transmission Constrained Areas. This third test involving deliverability to load pockets was debated extensively among stakeholders involved in this Deliverability test. As explained below, this third type of assessment may be an issue for the larger Resource Adequacy group to consider as a general Resource Adequacy requirement, rather than be subsumed as a third part of this technical Deliverability assessment.

Each of these assessments is discussed in greater detail below and in the Attachments.

A. Deliverability Of Generation To The Aggregate Of Load

As part of developing its proposal to comply with FERC’s Order No. 2003 regarding the interconnection of new generating facilities, the ISO developed and proposed to FERC a “deliverability” test (but not a requirement). The purpose was to begin to assess the deliverability of new generation to serve load on the ISO’s system. Recent experience

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indicates that while California has added needed new generating capacity to the system over the past few years, not all of that capacity is deliverable to load on the system because of the presence of transmission constraints. Therefore, although not requiring all new generation to be deliverable, the ISO proposed in its Order 2003 compliance filing to assess deliverability so that the sponsors of new generation projects can accurately assess their ability to deliver the output of the new plants to the aggregate of load for resource adequacy counting purposes. This first assessment reflects the deliverability test and the baseline analysis envisioned by the ISO to be conducted as part of this interconnection process.

The ISO recommends that a generating facility deliverability assessment be performed to determine the generating facility's ability to deliver its energy to load on the ISO Controlled Grid under peak load conditions. Such a deliverability assessment will provide necessary information regarding the level of deliverability of such resources with and without Network Upgrades (i.e., major transmission facilities), and thus provide information regarding the required Network Upgrades to enable the generating facility to deliver its full output to load on the ISO Controlled Grid based on specified study assumptions. That is, a generating facility's interconnection should be studied with the ISO Controlled Grid at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the ISO Controlled Grid, consistent with the ISO's reliability criteria and procedures. (This definition for deliverability comes from the FERC interconnection order, and this methodology for assessing deliverability has been developed from consultation with PJM officials about their already-established practices.)

In addition, the ISO recommends, based on guidance in FERC Order 2003, that the deliverability of a new resource should be assessed on the same basis as all other existing resources interconnected to the ISO Controlled Grid.

Because a deliverability assessment will focus on the deliverability of generation capacity when the need for capacity is the greatest (i.e. peak load conditions), it will not ensure that a particular generation facility will not experience economic congestion during other operating periods. Therefore, other information (i.e. congestion cost analysis for all hours of the year) would be required in addition to the deliverability assessment to evaluate the congestion cost risk of a take-or-pay energy purchase contract with a particular generation facility.

Attachment 1, Generator Deliverability Assessment, contains the technical details of this proposed methodology.

B. Deliverability of Imports

California is now, and will likely remain, dependent on imports to satisfy its energy and resource requirements. Therefore, it is likely that as part of fulfilling their obligation to procure sufficient resources (reserves) in the forward market to serve their respective loads, the IOUs will contract with out-of-state resources. This is appropriate and necessary.

The ability to rely on imports to satisfy reserve requirements is entirely dependent on the *deliverability* of such out-of-state resources to and from the intertie points between the ISO's system and the neighboring systems. While the existing system may be able to satisfy the procurement plans of any one LSE, it likely will not be able to transmit the sum of LSEs' needs. Each LSE may well be utilizing the same potentially constrained transmission paths to deliver their out-of-state resources. Therefore, the transmission system should be checked to make sure that simultaneous imports can be accommodated.

When relying on imports to serve load, each LSE should be required to ensure that they have assessed the deliverability of such resources from the tie point to load on the ISO's system.

More specifically, this "Strawperson" proposes that each LSE, in conjunction with the ISO, be required to perform an integrated analysis on the annual procurement plans and the long-term procurement plans to ensure their identified resources are deliverable to load and that the necessary transmission capacity will exist on the system. Such an analysis should be performed using similar techniques used for operational transfer capability ("OTC") studies but would look at specific resource import scenarios expected in the future. Adverse internal generation availability and loop flow scenarios should be developed to adequately evaluate the capabilities of the transmission system to deliver imports to aggregate load.

Additionally, some kind of determination is needed regarding the ability of resources to be delivered to the tie point with California. Several stakeholders suggested a requirement for *firm* transmission rights over the neighboring system's transmission system would be too limiting, as some entities may want to optimize a portfolio of resources. This "Strawperson" proposal omits any deliverability requirement outside of California because it is beyond the scope of this technical explanation of a deliverability assessment. However, the ISO anticipates further discussion on the need for some kind of assurance that resources outside of California can deliver necessary MWs to the tie points.

In reviewing this paper several participants also questioned whether this Deliverability of Imports test is identical to the ISO's planned CRR simultaneous feasibility test (SFT). Both tests would use the same transmission network model for the same study year, and would consider the same contingencies. However, at this time the SFT models simultaneous flow limits in order to ensure that appropriate contingencies are covered, while the proposed Deliverability of Imports test has the ability to simulate each

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contingency that needs to be covered. The additional complexity and correspondingly improved accuracy would be a feature of the Deliverability of Imports test but not the SFT.

Attachment 2, Deliverability of Imports Assessment, contains the technical details of the deliverability of imports study methodology.

C. Deliverability To Load Within Transmission Constrained Areas

Load within transmission-constrained areas, known as “load pockets,” present unique circumstances for the assessment of deliverability. A load pocket is an electrically cohesive area that is a sub-area of the ISO Control Area. (For example, the San Francisco Bay, San Diego, LA Basin, Fresno, NP15 and SP15 areas are examples of constrained transmission areas.) These load pockets can be defined by the impact of generators within the sub-area upon the contingencies known to limit operations in that sub-area. The boundaries of load pockets can be drawn to include generators that have calculated impacts beyond a certain percentage upon those contingencies. Load buses also can be similarly assigned and defined within these sub-areas based on their impact on the same contingencies.

Load pockets are highly dependent both on the availability of generation within the constrained area and the limited transfer capability of the transmission system. Because the transmission capability within a “load pocket” is so critical, this “Strawperson” proposes that special focus be placed on assessing the deliverability of the procured resources to serve load in such locally constrained areas of the transmission system. However, considerable discussion was held among stakeholders who believe the deliverability of resources outside these designated sub-areas to loads inside these “pockets” should be handled within the grid planning process, and not be part of this deliverability test. To inform further discussion, an understanding of the ISO’s Grid Planning process and its similarity and differences to this proposed “Deliverability to Load” assessment may be useful.

The ISO Grid Planning process is designed to ensure the ISO Controlled Grid meets NERC/WECC Planning Standards, as well as some ISO-specific Grid Planning Standards. Currently the NERC/WECC Planning Standards do not address resource adequacy and deliverability issues (such as the deliverability of resources to load pockets,) while one of the more stringent standards that are specific to the ISO partly addresses the availability of resources in a particular area.

The San Francisco Greater Bay Area Generation Outage Standard effectively requires that three or four specific generation units are deemed out of service in the power system base case for analyzing transmission line contingencies. This Standard was developed after a June 14, 2000 localized resource shortage in the San Francisco Bay Area resulted

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in rolling blackouts that were necessary to ensure compliance with the WECC Minimum Operating Reliability Criteria (MORC.)

Because the San Francisco Greater Bay Area Generation Outage Standard specifically considers the availability of resources, this facet of the ISO Grid Planning Process falls into a category where both Transmission Adequacy and Resource Adequacy overlap. The ISO Grid Planning Standards Committee periodically reviews other areas of the ISO Grid to determine if additional specific standards are necessary upon review of generation availability data within those other areas. If other special Standards were approved for other transmission constrained areas, presumably the Transmission and Resource Adequacy assessment methodologies would overlap for the areas covered by these Standards.

To further underscore the distinction between grid planning and resource adequacy standards, it should be noted that the CPUC's rulemaking on transmission assessment practices anticipates a resource planning process that considers the economic trade-off between Load, Transmission, Generation and possibly RMR contracts. The ISO Grid Planning process would be limited to considering only transmission projects after the other alternatives have been considered. "Staff suggests that the Commission's transmission determination made as part of its review of the IOUs long-term procurement plans should be reflected in the CAISO's transmission planning process."¹

In addition, a NERC taskforce recently issued a series of draft recommendations, including support for the eventual creation of deliverability assessment standards: "NERC shall develop assessment practices and reporting processes to verify that resources identified by load serving entities (LSEs) to meet resource adequacy requirements are simultaneously deliverable to the LSEs' loads. The assessment practices shall also determine whether the simultaneous import capabilities are sufficient to satisfy the import capability assumptions included in the resource adequacy assessments."² Although implementation of such proposed NERC standards is not likely in the immediate future, this task force recommendation does indicate that deliverability is a distinct feature from the existing NERC/WECC Planning Standards, and that some minimum national standards for deliverability assessment are needed.

Finally, some participants within this Deliverability workgroup raised questions related to RMR criteria. This "Strawperson" proposal assumes that RMR criteria would be an insufficient test for deliverability *in the long-term* because RMR is a year-ahead process. The options for providing local area reliability service are limited to signing RMR contracts or capital projects that can be completed within one year. Because of these limited options, the RMR criteria are typically less stringent than the ISO Grid Planning Standards or this proposed Deliverability to Load assessment. These latter two

¹ Page 6, CPUC Rulemaking 04-01-026; Order Instituting Rulemaking on policies and practices for the Commission's transmission assessment process.

² Draft Resource and Transmission Adequacy Recommendations report, presented at the March 23-24, 2004 meeting of the NERC Resource and Transmission Adequacy Task Force.

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assessments are applicable for long-term planning purposes when long-lead time new transmission or generation projects are possible options. RMR criteria could, however, offer a test for deliverability to load pockets in the short-term.

The ISO initially proposed this “Deliverability to Load” standard to ensure that the CPUC and the ISO have a common methodology, from both a Transmission Adequacy and Resource Adequacy perspective, for assessing large load pockets like the San Francisco Bay area. It is possible this third “leg” of a deliverability assessment could be considered separately from the “Strawperson” proposal because there is some overlap among standards and a broader perspective may be needed. However, the ISO believes this a critical issue to be resolved in the context of the utilities’ procurement activities, so that each load-serving entity can make a meaningful assessment of the trade-off between procuring local generation, building new transmission to serve load in the constrained area, or developing demand response. The details of this proposed methodology for Deliverability to Load in Transmission Constrained Areas are included for a fuller explanation.

In summary, the focus of this proposed assessment is to ensure the appropriate probability that severely constrained transmission areas will have sufficient transmission so that an adequate amount of generation from resources located outside the local area can be delivered to serve the local load. Specifically, the probability of load within the local area, exceeding the available capacity resources located in the local area and imported into the local area, should be equivalent to the probability of control area load exceeding the amount of capacity resources available to the overall control area. This methodology ensures a consistent level of resource adequacy across the ISO Controlled Grid.

The ISO anticipates further discussion on this proposed assessment and notes that the potential CPUC requirements upon LSEs – to address both deliverability and local reliability within their resource plans – could be determined in an integrated fashion through the suggested methodology in Attachment 3.

Attachment 3, Deliverability to Load in Transmission Constrained Areas, contains the technical details of this deliverability to load study methodology.

D. Summary

Several entities reviewing this “Strawperson” proposal questioned how the ISO might tie together these three suggested “buckets” of Deliverability, and when individual resources might be determined or categorized as “deliverable” based on these proposed tests.

The Generation Deliverability Assessment would be performed in the annual baseline analysis and in every new System Impact Study as part of the generation interconnection

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process. Resources that pass the deliverability assessment could be counted to meet reserve margin requirements and resources that don't pass could not.

The Deliverability of Imports assessment would be performed during the review of all LSE's long term and short term resource plans. Firm import information is an input to the generation deliverability assessments. Therefore, new firm import procurement plans would need to be tested using the generator deliverability methodology to ensure that the additional imports do not impact the deliverability of generation that has already passed the generation deliverability test. Once the resource plans are approved, the import assumptions for future generation deliverability assessment would be updated as needed.

The Deliverability to Load test would be performed during the development of the *long term* resource plans. Solutions for resolving resource deficient load pockets could include the construction of resources needed to meet reserve margin requirements but located in the deficient load pocket to mitigate the deliverability to load deficiency. The construction of resources within the load pocket could be by any developer of generation—a procurement contract with that new generator should ensure that it is actually built.

The Deliverability of Imports and the Deliverability to Load in Transmission-Constrained Areas would, generally, utilize common methods and terminology. However, the definition of the area to be analyzed for the Deliverability of Imports assessment is already defined as the ISO Control Area boundary. This boundary is determined almost exclusively by facility ownership and service areas rather than electrical characteristics. In contrast, the boundary for load pockets to be analyzed would be determined only by electrical characteristics. Operational Transfer Capability (OTC) is a term that applies to WECC paths that correspond to most of the ISO Control Area Boundary. OTCs are not calculated for most load pocket boundaries because power is not scheduled across these boundaries.

Because the ISO lacks critical data necessary to conduct a meaningful “test-run” of this methodology, preliminary study results would be misleading. One participant helpfully suggested that, should results be required quickly in time for LSEs summer 2005 resource procurement activities, then historical data could be utilized. The ISO appreciates this suggestion but is concerned that planned transmission upgrades and new generation would not be considered. In addition, a review of the day-ahead, hour-ahead, and real-time markets for both inter-zonal and intra-zonal congestion for the peak load day for each of the summer months could take considerable time. The ISO also emphasizes that continued stakeholder input and review is strongly encouraged if any of these procedures are undertaken. It is fully expected that this deliverability validation process would be tested and evaluated on existing resources to ensure that the results are reasonable, equitable and consistent with engineering judgment, and that refinements will be made as needed.

Generator Deliverability Assessment**1.0 Introduction**

A generator deliverability test is applied to ensure that capacity is not "bottled" from a resource adequacy perspective. This would require that each electrical area be able to accommodate the full output of all of its capacity resources and export, at a minimum, whatever power is not consumed by local loads during periods of peak system load.

Export capabilities at lower load levels can affect the economics of both the system and area generation, but generally they do not affect resource adequacy. Therefore, export capabilities at lower system load levels are not assessed in this deliverability test procedure.

Deliverability, from the perspective of individual generator resources, ensures that, under normal transmission system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other capacity resources in the vicinity. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of the control area, subject to contingency testing.

In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of capacity resources for meeting resource adequacy requirements.

In actual operating conditions energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that the existing and proposed certified capacity in any given electrical area could simultaneously deliver full energy output to the control area.

The electrical regions, from which generation must be deliverable, range from individual buses to all of the generation in the vicinity of the generator under study. The premise of the test is that all capacity in the vicinity of the generator under study is required, hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies should be tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is appropriately distributed as proposed in Table 1.

Failure of the generator deliverability test when evaluating a new resource in the System Impact Study brings about the following possible consequences. If the addition of the resource will cause a deliverability deficiency then the resource should not be fully counted towards resource adequacy reserve requirements until transmission system upgrades are completed to correct the deficiency.

A generator that meets this deliverability test may still experience substantial congestion in the local area. To adequately analyze the potential for congestion, various stressed conditions (i.e., besides the system peak load conditions) will be studied as part of the overall System Impact Study for the new generation project. Depending on the results of these other studies, a new generator may wish to fund transmission reinforcements beyond those needed to pass the deliverability test to further mitigate potential congestion—or relocate to a less congested location.

The procedure proposed for testing generator deliverability follows.

2.0 Study Objectives

The goal of the proposed ISO Generator deliverability study methodology is to determine if the aggregate of generators in a given area can be simultaneously transferred to the remainder of ISO Control Area. Any generators requesting interconnection to the ISO Controlled Grid will be analyzed for “deliverability” in order to establish the amount of deliverable capacity to be associated with the resource.

The ISO deliverability test methodology is designed to ensure that facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner.

3.0 Baseline analysis

Deliverability Test Validation: This procedure was derived from the deliverability test procedure currently used by PJM. Adaptations to the PJM procedure were necessary due to the considerable physical differences between the PJM system and the ISO-Controlled Grid. During the initial implementation of this procedure, it will be tested, and evaluated on existing resources to ensure that the results are reasonable, equitable, and consistent with engineering judgment. Stakeholders will review the results of this validation process. The deliverability test procedure will be refined as needed.

In order to ensure that existing resources can pass this deliverability assessment, an annual baseline analysis, with the most up-to-date system parameters, must first be performed by applying the same methodology described below on the existing transmission system and existing resources. Identified deliverability problems associated with generation that exist prior to the implementation of this deliverability test may be mitigated by transmission expansion projects if the capacity is needed and/or the project is economically justifiable. Generation deliverability limitations on currently existing generation can be allocated among multiple generators contributing to the same problem based on the incremental flow impact that each generator contributes to the problem. The deliverability of both existing and new generators that are certified as deliverable will be maintained by the annual baseline analysis and the transmission expansion planning process.

4.0 General Procedures and Assumptions

Step 1: Build an initial powerflow base case modeling ISO resources at the levels specified in Table 1. This base case will be used for two purposes: (1) it will be analyzed using a DC transfer capability/contingency analysis tool to screen for potential deliverability problems, (2) it will be used to verify the problems identified during the screening test, using an AC power flow analysis tool. All new generation applicants in the interconnection queue ahead of the unit under study are set at 0 MW (but available to be turned on for the screening analysis but not for the AC power flow analysis). Then the capacity resource units in the queue electrically closest to the unit being studied are turned on in accordance with Table 1 until the net ISO Control Area interchange equals the interchange target, also described in Table 1. Generation applicants after the queue position under study are not modeled in the analysis.

Step 2: Using the screening tool, the ISO transmission system is essentially analyzed facility by facility to determine if normal or contingency overloads can occur. For each analyzed facility, an electrical circle is drawn which includes all units that have 5% or greater distribution factor (DFAX) on the facility being analyzed. (A 10% DFAX is used for 500 kV facilities.) Then load flow simulations are performed, which study the worst-case combination of generator output within each 5% DFAX circle. The 5% DFAX circle can also be referred to as the Study Area for the particular facility being analyzed.

The output of capacity units in the 5% circle are increased starting with units with the highest DFAX and proportionately displacing generation, outside the 5% circle, to maintain a load and resource balance. Any, several, or all the units within the 5% circle can be set at 100% output, up to a movement of 3000 MW or the twenty¹ units with the largest impact on the transmission facility.

Step 3: Using an AC power flow analysis tool, verify the overload scenarios identified in the screening analysis.

Step 4: Verified overloaded facilities with a DFAX from the new unit greater than 5% on lines 230 kV and below or 10% on 500 kV lines would need to be mitigated for the new unit to pass the deliverability test.

¹ The cumulative availability of twenty units with a 7.5% forced outage rate would be 21%--the ISO proposes that this is a reasonable cutoff that should be consistently applied in the analysis of large study areas with more than 20 units. Hydro units that are operated on a coordinated basis because of the hydrological dependencies should be moved together, even if some of the units are outside the study area, and could result in moving more than 20 units.

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Table 1: Resource Dispatch Assumptions

Resource Type	Base Case Dispatch	Available to Selectively Increase Output for Worst-Case Dispatch?	Available to Scale Down Output Proportionally with all Control Area Capacity Resources?
Must-Take Capacity Resources			
• Nuclear	maximum dependable capacity	N	Y
• QF contracts	historical output	Y (up to contract limit)	Y
RMR	Dispatch as necessary to meet local area requirements	Y	Y
Energy Limited Capacity Resources			
• Hydro	Drought conditions, historical output, 90% confidence factor* for output during summer peak load hours** (An average hydro scenario will also be analyzed)	Y	Y
• Combustion Turbines with run-hour limitations	Approximately 50% of dependable capacity	Y	Y
Other Dispatchable Capacity Resources			
• Combined cycle gas, Steam turbine gas/coal, geothermal, biomass	Approximately 90% of dependable capacity	Y	Y
Intermittent Capacity Resources			
• Wind	90% confidence factor* for output during summer peak load hours** (An average wind scenario will also be analyzed)	Y	Y
• Solar	90% confidence factor* for output during summer peak load hours** (An average solar scenario will also be analyzed)	Y	Y
Energy Resources	Minimum commitment and dispatch to balance load and maintain expected imports	N	Y
Imports			
• Existing Transmission Contracts	Schedule/flow at contract capacity	N	N
• Dynamic Schedules	Schedule/flow at contract capacity	N	N
• Unit contingent LSE Import	Schedule/flow at contract capacity	N	Y

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contracts for Capacity Resources			
• System resource LSE Import contracts	Schedule/flow at contract capacity	N	N
• Spot Market	Historical availability— analyze reasonable scenarios consistent with resource adequacy planning assumptions	N	Y (for unit contingent)
Load			
• Non-pump load	90% to 100% of maximum load.	N	N
• Pump load	Within expected range for Summer peak load hours**	N	N

* 90% confidence factor means that the generation is expected to be dispatched, based on historical data, above the base case assumption during 90% of the Summer peak load hours.

** Summer peak load hours are the 50 to 100 hours in the months of August and September when Control Area load is between 90% and 100% of maximum annual load. August and September were chosen because that is when load is typically high and hydro availability tends to run short during drought conditions.

Draft Straw-Person Deliverability Proposal**Distribution Factor (DFAX)**

Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources "available to scale down output proportionally with all control area capacity resources in the Control Area", shown in Table 1. Generation units are scaled down in proportion to the dispatch level of the unit.

G-1 Sensitivity

A single generator may be modeled off-line entirely to represent a forced outage of that unit. This is consistent with the ISO Grid Planning Standards that analyze a single transmission circuit outage with one generator already out of service and system adjusted as a NERC level B contingency. System adjustments could include increasing generation outside the study area. The number of generators increased outside the study area should not exceed the number of generators increased inside the study area.

Municipal Units

Treat like all other Capacity Resources unless existing system analysis identifies problems.

Energy Resources

If it is necessary to dispatch Energy Resources to balance load and maintain expected import levels, these units should not contribute to any facility overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines. Energy Resource units should also not mitigate any overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines.

WECC Path Ratings

All WECC Path ratings (e.g. Path 15 and Path 26) must be observed during the deliverability test.

Pmax* DFAX Impact

Generators that have a $(\text{DFAX} * \text{Generation Capacity}) > 5\%$ of applicable facility rating or OTC will also be included in the Study Area.

Deliverability of Imports Assessment

This deliverability assessment focuses on resources imported into the Control Area. WECC path ratings are established assuming favorable system conditions. Operational Transfer Capability (OTC) studies are performed seasonally for the upcoming season for operational purposes using expected and adverse system conditions, but are not regularly performed for planning purposes. A deliverability test is required to ensure that imports necessary for resource adequacy can be accommodated under expected and adverse system conditions such as resource shortages. These studies would be performed using similar techniques used for OTC studies but would look further into the future, and would test the simultaneous deliverability of Firm Imports needed to ensure resource adequacy. The basic steps are listed below.

- 1. Stability and Post-Transient Analysis**
 - a) Start from ISO Controlled-Grid summer peak base cases.**
 - b) ISO will model imports specified in the LSE resource plans, existing transmission contracts, and dynamic schedules.**
 - c) ISO in coordination with the PTOs will develop generation, and loop flow scenarios to stress transmission system**
 - d) ISO and/or PTOs will check for ISO Grid Planning Criteria violations**
 - e) ISO and/or PTOs will propose plans to mitigate criteria violations**
- 2. Powerflow Analysis**

The Generator Deliverability Assessment will incorporate imports specified in the LSE resource plans, existing transmission contracts, and dynamic schedules into the analysis. Proposed new import contracts that contribute to deliverability problems in that assessment will be identified, and mitigation alternatives will be suggested.

Deliverability to Load in Transmission Constrained Areas

This deliverability assessment focuses on the delivery of energy from the aggregate of capacity resources to an electrical area experiencing a capacity deficiency. It can be discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy will be able to be delivered to Control Area load, regardless of cost, from the aggregate of capacity resources available to the Control Area.

The determination of the reserve requirement is based on the assumption that the delivery of energy from the aggregate of capacity resources to control area load will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout the control area and the ability of the transmission system to reliably deliver energy to portions of the control area experiencing capacity deficiencies.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of a Capacity Emergency Transfer Objectives (CETO) and Capacity Transfer Limits (CTL) for various electrical sub-areas of the ISO Control Area. A CETO represents the amount of MWs that a given sub-area must be able to import in order to remain within the CPUC resource adequacy framework requiring that the probability of occurrence of load exceeding the available capacity resources is consistent across the Control Area.

To analyze the deliverability to load, electrically cohesive load areas must first be defined. These areas are sub-areas of the ISO Control Area (e.g. San Francisco Bay area, San Diego area, LA Basin area, Fresno area, NP15, SP15, etc). These sub-areas are defined based on the impact of generators, potentially within the sub-area, on the contingencies known to limit operations in the sub-area. Sub-area boundaries could be drawn to include generators based on the calculated impacts on those contingencies. Load buses are similarly assigned to these sub-areas based on their impact on the same contingencies.

Once a sub-area is defined, the CETO for that sub-area must be calculated using a reliability simulation tool such as Henwood RiskSym, or GE MARS. Using the simulation tool, determine the import capability of the load area necessary to ensure the LOLP inside the area is consistent with the rest of the control area—this value is the CETO for that sub-area.

The next step in the analysis is to calculate a generation forced outage target (GFOT). The GFOT will be equal to the internal area generation (G) plus the CETO minus the internal sub-area peak load and losses (L) or $GFOT = G + CETO - L$. An example of this concept is shown in Figure 1.

Once the GFOT is determined, specific unit forced outage scenarios need to be developed for modeling within a power flow base case model. Using the individual generator

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Attachment 3

forced outage rates, develop a base generator outage scenario by selecting the units with highest outage rates until the GFOT is satisfied. Variations of the base generator outage scenario should also be developed by removing the most critical units from the model that result in adversely impacting the import capability of the sub-area. At least half of the generation in the outage scenario should be from the base outage scenario, and the amount of generation forced out in the scenario should not exceed the GFOT. Power flow base cases will be developed for each of the generation outage scenarios.

In general, all single element transmission contingencies should be tested on each of the power flow base cases developed. Multiple element contingencies that transmission system operators consider to have a sufficiently high likelihood of occurring should be treated as a single contingency and should also be tested. System performance for each of the contingencies should be measured against NERC Category B System Limits or Impacts for single transmission element outages and NERC Category C System Limits or Impacts for multiple transmission element outages, in the ISO Grid Planning Criteria. If any of the applicable performance limits are violated then the local area does not pass the deliverability to load assessment and should be mitigated as soon as practicable in the resource and transmission plans.

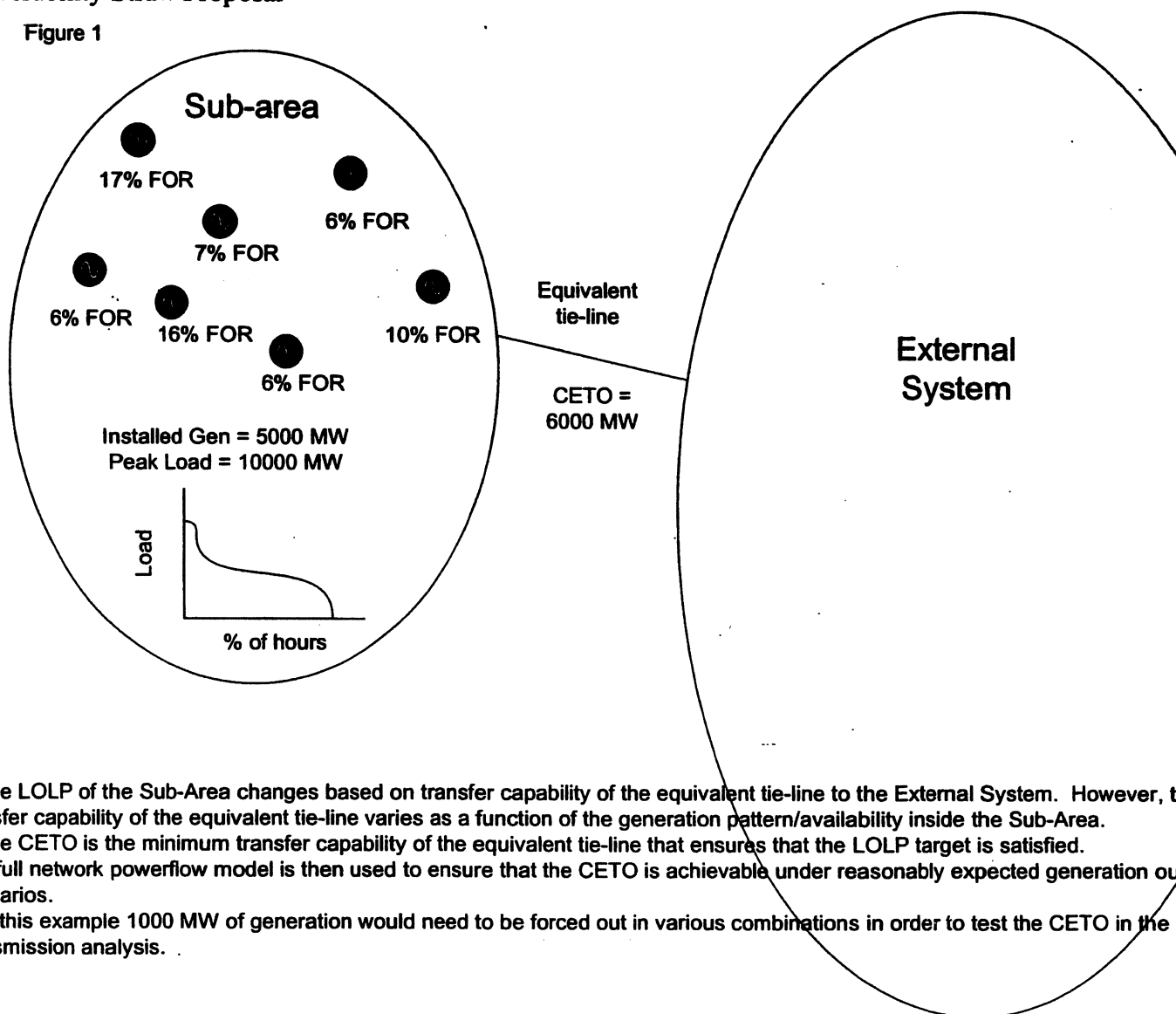
Once it is determined that the deliverability to load assessment of the area can be passed, a Capacity Transfer Limit is developed to establish target procurement levels for resources located in the local area. Economically procuring resources within the sub-area as part of the resource plan will tend to reduce RMR costs, and mitigate local market power. A Capacity Transfer Limit (CTL) for the area is developed by starting with the worst case generation scenario in the CETO test and then removing generators with the highest effectiveness factors that do not already have procurement contracts until a performance limit is violated. If the CETO test was not passed then the CTL should be set equal to the CETO.

Load serving entities with load in the sub-area should include resources, located in the sub-area, in their procurement plans so that a minimum of 90% of their load in the area minus their proportion of the CTL is served by resources in the local area. An LSEs proportion of the CTL should be calculated as a pro rata share in proportion to their percentage of the load in the area once existing transmission contractual obligations have been removed from the CTL.

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Figure 1



- * The LOLP of the Sub-Area changes based on transfer capability of the equivalent tie-line to the External System. However, the transfer capability of the equivalent tie-line varies as a function of the generation pattern/availability inside the Sub-Area.
- * The CETO is the minimum transfer capability of the equivalent tie-line that ensures that the LOLP target is satisfied.
- * A full network powerflow model is then used to ensure that the CETO is achievable under reasonably expected generation out scenarios.
- * In this example 1000 MW of generation would need to be forced out in various combinations in order to test the CETO in the transmission analysis.

APPENDIX E

Assessment of Total Import Capacity

Deliverability Workshop Follow-Up: Assessment of Total Capacity into ISO Control Area

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, an action item was assigned to the California ISO. As requested, the ISO has been coordinating a detailed technical discussion and development of a proposal for establishing the total import capacity, for each import path, to be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. This proposed approach will be presented at the next Deliverability Workshop scheduled for May 5, 2004.

Transmission constraints can impact the simultaneous deliverability of imports and internal generation. As a result, the interaction between the deliverability of imports and the deliverability of generation needs to be examined. The proposed generation deliverability assessment includes, as an input assumption, the amount of imports and existing transmission contract related encumbrances electrically flowing over the ISO Controlled Grid.

One of the observations from the Workshop was that LSEs needed to have results of the deliverability assessments in advance of submitting their resource plans to the CPUC for the year-ahead review. The generation deliverability assessment would provide results in advance. However, the deliverability of imports assessment initially described was an after-the-fact review of all of the LSE resource plans combined.

Because of the need for up-front information the ALJ assigned the ISO to lead a smaller group of Workshop participants to develop a methodology for determining the total amount of import capacity, by import path, which could be available to LSEs.¹ This document describes a proposal for a methodology developed by the subgroup.

Discussion of Proposed Approach

Whatever import capacity is available to LSEs for resource adequacy planning purposes should also be the basis for the import assumptions in the internal generation deliverability analysis. Because of the interaction between the deliverability of imports and the deliverability of internal generation, one should not simply determine the maximum import capability under favorable conditions and make that import capability available to LSEs for developing their resource plans. This approach assumes that all the import capability is needed and will be used for resource

¹ Determining a methodology for allocating import capability to LSEs was not an assignment of this working group.

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Assessment of Total Import Capacity

adequacy planning purposes, an assumption that could result in impairment of deliverability of internal generation. (This would be inconsistent with the consensus from previous workshops that the deliverability of generation internal to the ISO grid should be preserved.) Furthermore, it is likely that, compared to a more reasonable import allocation, more of the allocated import capability might remain unused by an LSE to meet its resource adequacy requirement at the expense of more internal generation being available to meet an LSE's resource adequacy requirement.

Workshop participants proposed that historical import information should be the basis for determining the initial amount of import levels to be allocated to LSEs. Following this suggestion, the ISO reviewed actual import flows and schedules during peak load hours in 2003. After initial review of the data, it appears that 2003 saw the highest import levels in the last five years during peak load periods.

In addition to using historical data, existing transmission contract (ETCs) information should also be utilized. It is assumed that the entities that have contracted for the transmission capacity are already relying on this import capability in their resource plans, so this transmission should not be reallocated.

The impact of these total import levels would likely affect the deliverability of some existing generation, and the interplay between the deliverability of these existing generators and imports needs to be addressed. One of the key benefits of this proposed approach is that a clear deliverability benchmark would be established up front, it would be the starting point for future years, and LSEs would have some flexibility within this structure to adjust their resource adequacy plans to find an appropriate balance between imports and existing generation inside California.

Proposed Methodology

Initial Import Level

The proposed approach for combining both historical information and contractual information is to add final transmission import schedules (day-ahead, hour ahead, and real-time) not associated with ETCs, to ETC reservations on a path by path basis. One could then verify that this sum would not have exceeded the historical Operational Transfer Capabilities (OTCs) and make the appropriate adjustments. This methodology could be applied using several historical high load, high import hours and then taking the average total import as the initial import level.

Generation Deliverability Analysis

Using the initial import level as an input assumption, a baseline analysis of the deliverability of generation to the aggregate of load would be performed as described in the Strawperson

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Assessment of Total Import Capacity

Deliverability Proposal discussed in the Workshops. This benchmarking analysis would establish the deliverability of internal generation.

Per the ISO's Compliance filing for FERC Order 2003, the procedures for interconnection of new generators to the ISO controlled grid includes a Deliverability Assessment as part of the required technical studies. This assessment on new generators would be performed using the same methodology described in the Strawperson Proposal. The deliverability of existing generation already determined to be deliverable in the baseline deliverability analysis would be preserved. Once the new generator's deliverability level is established, its deliverability would be maintained as well.

The deliverability of new firm import contracts that utilize transmission import capacity allocated or acquired through trade by an LSE also would be maintained. These contracts would be modeled in future baseline deliverability studies. New firm import capacity could be identified in future baseline studies and allocated to LSEs for their use.

Generation retirements would be modeled and the deliverability impact on existing internal generators and imports would be included in the results of the baseline deliverability studies.

Deliverability Priority

If the baseline deliverability analysis for existing generation determines that the initial import level assumption is reducing the deliverability of internal ISO grid generation, then the initial import levels will be reduced and the baseline deliverability analysis will be re-run. Although it is not anticipated that import levels will have to be reduced significantly from their initial level, this issue may need to be reassessed after the analysis is completed, consistent with the "Review of Results" paragraph (below.)

New resources that are determined to be deliverable in the interconnection process, either because there is adequate existing capacity or through the construction of network upgrades, should have equal priority with pre-existing deliverable resources.

Make Results of Deliverability Assessment Available for Use

Once the deliverability assessment is completed the results will be provided for use in developing year-ahead LSE resource procurement plans for resource adequacy purposes.² The total import capacity, by path, determined to be deliverable would need to be allocated to LSEs using some allocation methodology that has yet to be defined.

² Operational requirements of the various local areas (i.e., RMR areas) would need to be addressed so LSEs have the necessary information to develop their resource procurement plans. This includes operational requirements such as the amounts and locations of generation needed to be on line and the potential generation retirements that could increase local area requirements. The deliverability to load methodology should focus on these requirements.

APPENDIX E

Assessment of Total Import Capacity

(Optional Step) Modify Results of Deliverability Assessment based on Economic Tradeoff between Import Capacity and Internal Generation Capacity

This step assumes that the deliverability of existing resources may not necessarily be preserved, and could be reduced as needed to increase the deliverability of imports, if it is determined that more economic capacity can be obtained from import levels that exceed the total import capability allocated to LSEs. Some sub-group participants had concerns regarding the logistics of implementing this step, and there is no consensus whether or not this step should be included in this general methodology.

Review of Results of Generation and Import Deliverability Assessment Methodology

As part of the initial implementation of this analysis, the test results for generation and import deliverability should be evaluated to ensure they are reasonable, equitable, and consistent with engineering judgment. Stakeholders would help review the reasonableness of these initial test results, and, if necessary, the deliverability test procedure could be refined.

Note: Assessing Deliverability and Transmission Planning

PG&E participated throughout this sub-group and reiterates its position that deliverability assessments, should be developed in the transmission planning process and the generation interconnection process.

APPENDIX F: Allocating Total Import Deliverability

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Deliverability Workshop Follow-Up Allocating Total Import Deliverability

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, the California ISO was requested to coordinate a detailed technical discussion and develop a proposal for establishing the total import capacity, for each import path, which would be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. Three alternatives for allocating the total import deliverability were identified and discussed at the workshop:

1. Historical Rights Allocation Method
2. Pro Rata Allocation Method
3. Auction Method

The ISO's workshop assignment did not include coordinating the discussion on how to allocate the import deliverability. This document discusses the three allocation alternatives identified in the workshop and recommends adopting a hybrid of the Pro Rata Allocation Method and the Historical Rights Allocation Method—at least for the initial round of LSE resource procurement.

Historical Rights Allocation Method

The Historical Rights Allocation Method would allocate the deliverable capacity on each import path consistent with each LSE's historical rights to use that import path.

Some transmission ties were developed for the express purpose of importing specific resources, which the LSEs now depend on for their resource adequacy. The main advantage of the Historical Rights Allocation Method is that the resulting allocation would not conflict with any LSE's existing long-term commitment to an external resource.

Some of the disadvantages of the historical rights allocation method include the following:

- There may be disagreements on what constitutes a valid historical right, such as when an agreement that grants such rights terminates.
- It does not consider what import deliverability each LSE needs for its present resource procurement effort.
- It does not give LSEs with low historical import rights the chance to increase their rights, even if the other LSEs with historical rights no longer have a need for some of those rights.
- The resulting allocation has no relation to the size of an LSE's load or how much an LSE pays for transmission access.

In short, the Historical Rights Allocation Method is likely to unfairly endow a minority of the LSEs.

Pro Rata Allocation Method

The Pro Rata Allocation Method would allocate the deliverable capacity on each import path to each LSE that pays the applicable High Voltage Access Charge (HVAC) or Low Voltage Access Charge (LVAC) for that path in proportion to the LSE's load that is included in the billing determinant for that Access Charge. A pro rata share of the deliverable capacity of each High Voltage (i.e., above 200 kV) import tie would be allocated to each LSE that pays the HVAC. A pro rata share of the deliverable capacity of each Low Voltage tie would be allocated to each LSE that pays the Access Charge (which presently is the LVAC of the owning PTO) applicable to that tie.

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Unlike the Historical Rights Allocation Method, the Pro Rata Allocation Method would consider the size of an LSE's load and how much an LSE pays for transmission access. However, this method also has some shortcomings, including the following:

- It does not recognize the commitments an LSE may already have to take external resources or the LSE's reliance on those resources for resource adequacy.
- It does not consider what import deliverability each LSE needs for its present resource procurement effort.
- It does not give LSEs the chance to increase their rights, even if the other LSEs do not have a need for all of their import deliverability allocation.

Auction Method

The Auction Method would allocate the deliverable capacity on each import path to the LSEs that bid the highest in an auction. An appropriately constructed auction method has the potential to equitably allocate import deliverability capacity. In theory, the LSE that has the greatest need would bid the most and receive the import deliverability allocation. And, if the auction proceeds were used to lower the Access Charge, similar to FTR auction proceeds today, all transmission users would benefit.

However, today's auction methods are only for annual rights. For longer term procurement, certainty in the cost of rights over a longer time frame would be necessary. Therefore, it would take a lot of time and effort to develop auction rules that would achieve the intended results and not be subject to gaming. It is not realistic to expect that such rules could be developed, tested and implemented in time for the LSEs resource procurement activities next year (2005).

Hybrid Method

The Hybrid Method contains the best features of the Historical Rights Allocation Method and the Pro Rata Allocation Method and adds a few other features to recognize each LSE's previous resource adequacy planning measures as well as allow for future planning needs and interests. In addition, the Hybrid Method facilitates the LSEs' efforts to achieve resource adequacy without the complexity and uncertainty that the Auction Method would involve. The Hybrid Method contains the following steps:

Step 1: Allocate the import deliverability on each import path to each LSE that pays the applicable High Voltage Access Charge (HVAC) or Low Voltage Access Charge (LVAC) for that path in proportion to the LSE's load that is included in the billing determinant for that Access Charge.

Step 2a: Adjust the allocations determined in step 1 so that each LSE that already owns or has contracts (including assigned CDWR contracts) for external resources, and counts those resources to meet its resource adequacy requirement, receives an allocation of the import deliverability on the relevant import tie(s) large enough to accommodate the countable capacity of those resource that cannot be accommodated on the LSE's Existing Transmission Contract (ETC) rights. If the sum of an LSE's allocation from Step 1 plus its ETC rights is larger than the total of its existing external resources being counted to meet resource adequacy requirements, then no adjustment would be necessary.

Step 2b: To compensate for an increased allocation on one tie in Step 2a, an LSE's allocation on the other import ties would be reduced by a like amount, and the allocations of the other LSEs would then be increased. The ties on which the allocations of the other LSEs will be increased would be at the option of those other LSEs.

Step 3: As soon as an LSE determines that it may not need all of its import deliverability allocation (e.g., after reviewing the bids received in the resource procurement process), it would notify the other LSEs of the potential availability of surplus import deliverability, and identify the affected import ties and the amounts. Any LSE potentially interested in a surplus import deliverability allocation would inform the offering LSE of its interest.

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Step 4: Each LSE will use its allocation of import deliverability in conjunction with its resource portfolio to make the required demonstration of its resource adequacy. Any portion of the import deliverability allocation that is not needed for such demonstration would be released on a pro rata basis to the other LSEs that both requested it in Step 3 and then use it to make the required demonstration of its resource adequacy. To the extent no other LSE requests and uses the surplus import deliverability allocations in accordance with this Step 4, the LSE will retain its surplus import deliverability allocations and may use them to support resource procurement until the next import deliverability allocation cycle.

Step 5: In subsequent years, when import deliverability is allocated, an LSE will retain any portion of its previous import deliverability allocation as long as it is needed to count an external resource that it already owns or has under contract toward meeting its resource adequacy requirement. Such allocations will be accounted for in step 2a of future import deliverability allocations using this process. Once an LSE's contract or ownership for an external resource terminates, continued use of its import deliverability allocation for that resource received in Step 2a would become subject to a right of first refusal by the other LSEs that originally received the allocation in Step 1 and then lost it in Step 2b.

Relationship to CRRs

The CAISO is now in the process of determining how Congestion Revenue Rights (CRRs) will be allocated. In addition, there also is an existing process for auctioning Firm Transmission Rights (FTRs). CRRs (which will replace FTRs) provide their holders financial protection from congestion charges. But, they are not necessary to assure the physical ability to import a resource. As long as these deliverability and counting processes allow the sum of all LSE external resources to count only up to the import capability of the transmission, and no more, then adequacy should be assured. Costs of congestion (or excess demand on import capability) does not effect the LSEs resource adequacy, and when congestion is occurring, the ISO would still be getting physical imports into the area equivalent to the counted capability regardless of excess demand to use the import ties. Therefore, possession of CRRs or FTRs should not be a requirement for counting an external resource as deliverable.

Recommendation

The Hybrid Method described above has all of the advantages and avoids all of the problems of the Historical Rights Allocation Method and the Pro Rata Allocation Method. It also is much less complex than the Auction Method, and its outcome is much more likely to avoid unintended consequences. For these reasons, the Hybrid Method for allocating import deliverability is recommended.

APPENDIX G: Percent Variation From Peak

Percent Variation from Peak

2003			2002			2001			2000 (see note)			1999			1998 (see note)		
MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max	
1	42,689	0.00%	1	42,441	0.00%	1	41,419	0.00%	1	43,360	0.00%	1	45,884	0.00%	1	44,659.12	0.00%
2	42,584	0.25%	2	42,366	0.17%	2	41,392	0.07%	2	43,234	0.29%	2	45,705	0.39%	2	44,657.22	0.00%
3	42,539	0.35%	3	41,626	1.92%	3	41,186	0.56%	3	42,964	0.91%	3	45,494	0.86%	3	44,321.86	0.76%
4	41,975	1.67%	4	41,385	2.49%	4	40,699	1.74%	4	42,762	1.38%	4	45,449	0.95%	4	44,231.65	0.96%
5	41,734	2.24%	5	40,820	3.82%	5	39,805	3.90%	5	42,237	2.59%	5	45,145	1.81%	5	43,779.40	1.97%
6	40,664	4.74%	6	40,246	5.17%	6	39,669	4.23%	6	41,322	4.70%	6	44,196	3.68%	6	42,955.41	3.81%
7	40,653	4.77%	7	40,232	5.20%	7	38,375	7.35%	7	41,049	5.83%	7	44,153	3.77%	7	42,986.94	5.07%
8	39,236	8.09%	8	39,067	7.95%	8	38,148	7.90%	8	39,527	8.84%	8	42,831	6.65%	8	41,313.95	7.49%
9	39,064	8.49%	9	38,824	8.52%	9	37,720	8.93%	9	39,019	10.01%	9	42,496	7.38%	9	40,749.32	8.75%
10	38,149	10.64%	10	38,597	9.06%	10	37,001	10.67%	10	38,696	10.76%	10	41,423	9.72%	10	40,404.74	9.53%
11	38,144	10.65%	11	38,382	9.56%	11	36,743	11.29%	11	38,176	11.96%	11	41,040	10.56%	11	39,500.91	11.55%
12	37,793	11.47%	12	37,829	10.86%	12	35,428	14.46%	12	37,489	13.54%	12	40,831	11.01%	12	39,147.90	12.34%
13	36,004	15.66%	13	36,111	14.91%	13	33,899	18.16%	13	36,108	16.72%	13	39,058	14.88%	13	37,022.03	17.10%
14	34,735	18.63%	14	35,716	15.84%	14	33,482	19.16%	14	34,190	21.15%	14	37,797	17.62%	14	36,122.10	19.12%
15	33,287	22.03%	15	33,935	20.04%	15	31,442	24.09%	15	34,024	21.53%	15	36,102	21.32%	15	34,197.61	23.43%
16	30,863	27.70%	16	32,443	23.56%	16	30,093	27.35%	16	31,285	27.85%	16	33,739	26.47%	16	31,800.21	28.79%
17	30,530	28.48%	17	31,228	26.42%	17	29,196	29.51%	17	30,289	30.14%	17	32,926	28.24%	17	31,362.66	29.77%
18	28,207	33.93%	18	28,312	33.29%	18	27,006	34.80%	18	28,324	34.68%	18	29,258	36.23%	18	28,576.33	36.01%
19	26,481	37.97%	19	28,076	33.85%	19	26,422	36.21%	19	28,106	35.18%	19	27,052	41.04%	19	27,936.62	37.44%
20	25,660	39.89%	20	26,546	37.45%	20	25,545	38.32%	20	26,312	39.32%	20	25,808	43.75%	20	25,942.81	41.91%
21	25,154	41.08%	21	25,841	39.11%	21	25,017	39.60%	21	26,177	39.63%	21	25,385	44.68%	21	25,637.77	42.59%
22	23,942	43.92%	22	25,363	40.24%	22	24,071	41.88%	22	24,868	42.65%	22	24,261	47.13%	22	24,306.13	45.57%
23	23,921	43.97%	23	25,009	41.07%	23	23,898	42.30%	23	24,257	44.06%	23	24,214	47.23%	23	23,955.44	46.36%
24	23,432	45.11%	24	24,736	41.72%	24	23,371	43.57%	24	23,897	44.89%	24	23,660	48.43%	24	23,683.85	46.97%

*peak load day 8/16 was disrupted by interruptions
analysis on second highest peak day 8/17/2000

*peak load day 8/31 was
disrupted by interruptions,
analysis on second highest
peak day 8/12/1998

2 Hour average: 0.89%
4 Hour average: 2.69%
6 Hour average: 5.25%

Estimated MWs on 45,000 day
401.26
1209.15
2361.66

(End of Attachment A)